ACCESSION #: 9607150049

LICENSEE EVENT REPORT (LER)

FACILITY NAME: ST LUCIE UNIT 2 PAGE: 1 OF 6

DOCKET NUMBER: 05000389

TITLE: Manual Reactor Trip Due to High Main Generator Cold Gas

Temperature Caused by Valve Failure

EVENT DATE: 06/06/96 LER #: 96-002-00 REPORT DATE: 07/8/96

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: Edwin J. Benken, Licensing TELEPHONE: (407) 467-7156

COMPONENT FAILURE DESCRIPTION:

CAUSE: X SYSTEM: TK COMPONENT: TC MANUFACTURER: B045

B BA P I-075

REPORTABLE NPRDS: Y

Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On June 6, 1996, St. Lucie Unit 2 was operating in Mode 1 at 100 percent power. At 1232,.a temperature control valve (TCV) for the main generator hydrogen cooling system closed causing main generator hydrogen gas temperature to increase above the limiting value for continued operation. Operators initiated a manual reactor and turbine trip in accordance with approved plant procedure. All safety functions were satisfactorily met

and the plant was stabilized in Mode 3. Following the trip, a steam driven auxiliary feedwater pump tripped on over speed and a main feedwater pump tripped due to low system flow. Steam generator feedwater continued to be supplied by redundant pumps.

The cause of this event was the failure of a positioner feedback arm on the main generator hydrogen cooler temperature control valve. Failure of this component caused the valve to close and interrupt cooling water flow from the hydrogen cooling system.

Corrective actions: 1) Modifications were made to the hydrogen cooler TCV to eliminate the feedback assembly and reduce vibration. 2) Other temperature control valves were assessed and additional modifications made. 3) A plant modification is being evaluated to improve main feedwater pump performance. 4) A safety relief valve on the main feed system was modified to prevent unnecessary lifting. 5) Pressurizer response during the event was analyzed and a training bulletin was issued to clarify system response expectations. 6) A modification was implemented to eliminate the cause for the over speed of the steam driven auxiliary feedwater pump.


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DESCRIPTION OF THE EVENT

On June 6, 1996, St. Lucie Unit 2 was operating in Mode 1 at 100 percent reactor power. At 1209, a main generator temperature alarm (D-49) (EllS:IB) was received. In accordance with the Plant Annunciator Summary Procedure, ONOP 2-0030131, a utility non-licensed operator was dispatched to investigate the cause of the alarm, and the Main Generator Off-Normal Operating Procedure (ONOP 2-2200030) was entered. At that time, generator cold gas temperature indicated approximately 48.8 degrees Celsius and was decreasing. Approximately 1 minute from the initial receipt of the alarm, annunciator D-49 cleared, and generator cold gas temperature returned to normal and stabilized. Local investigation showed that the hydrogen cooler outlet temperature control valve, TCV 13-15 (EIIS:KB), was operating in automatic, as expected, and controlling at set point. TCV 13-15 regulates cooling water flow to control the hydrogen gas temperature in the main generator.

At 1232, main generator cold gas temperature, as displayed in the control room, again began to rise. The cold gas temperature quickly reached 53 degrees Celsius and in accordance with ONOP 2-2200030, the control room operators manually tripped the reactor and turbine to prevent damage to the main generator. Cold gas temperature returned to normal values following the trip. The control room crew implemented Standard Post Trip Actions in accordance with 2-EOP-01. A subsequent inspection found TCV 13-15 to be in the closed position.

During the performance of Standard Post Trip Actions, 2-EOP-01, operators observed that pressurizer (EIIS:AB) pressure and level decreased to approximately 1870 psia and 26 percent, respectively. These values were lower than those usually observed following a trip from full power. As a result of the pressurizer level decrease below 27 percent, the pressurizer heaters de-energized as designed. Operator actions to start a back up charging pump (EIIS:CB) and reduce SG feedwater flow to the steam generators to decrease Reactor Coolant System (RCS) (EIIS:AB) cooldown were effective in restoring pressurizer level to normal range. Pressurizer heaters were reset following the restoration of the pressurizer level to greater than 27 percent. At 1243, the control room operators completed 2-EOP-01, Standard Post Trip Actions, and entered the Reactor Trip Recovery Procedure, 2-EOP-02.

Following the reactor trip, control room operators observed that the 2B Main Feedwater (MFW) Pump (EIIS:SJ) had tripped. Additionally, a suction relief valve (SR-12470) (EIIS:SJ) on the 2A MFW Pump was reported to be lifting. The operators restarted the 2B MFW pump at 1245 and secured the 2A MFW pump. Suction relief valve SR-12470 reseated at approximately 1251. The Auxiliary Feedwater Actuation System for the 28 steam generator (AFAS-2) (EIIS:BA) actuated as designed following the plant trip. The 2A SG level remained above the actuation set point for AFAS-1 and therefore auxiliary feedwater did not immediately actuate for this SG.

At approximately 1247, AFAS-1 for the 2A SG actuated as designed, however the 2C AFW steam driven pump, which had been started during the AFAS-2 actuation, tripped due to over speed. Feedwater flow to the 2A and 2B steam generators was continually maintained using the 2A and 2B electrical AFW pumps. At 1435, feedwater flow to the steam generators was transferred back to the Main Feedwater pump and the 2A and 2B AFW pumps were subsequently secured. The plant was maintained stable in Mode 3 pending completion of a post trip review.



CAUSE OF THE EVENT

The reactor was manually tripped by utility licensed operators in accordance with procedures to mitigate the effects of a high gas temperature in the main generator. The primary cause of this event was the failure of a positioner feedback arm linkage for temperature control valve TCV 13-15, which became detached and caused the valve to close. The sudden loss of cooling water flow to the main generator hydrogen coolers caused by the valve's closure resulted in increased main generator gas temperatures which necessitated the unit shutdown. FPL investigated the failure of TCV 13-15 and determined that the failure mode which caused the feedback arm to separate was the loss of a linkage nut which had loosened and fallen from the assembly as a result of vibration experienced by the valve. The valve's design was such that positioner vibration was amplified as a result of the positioner being cantilevered off the valve actuator. The feedback arm linkage was not adequately secured for the service conditions.

The cause of the 2B MFW pump trip was low flow through the system following the reactor and turbine trip. The pump is equipped with a recirculation flow control valve designed to maintain minimum pump flow requirements, however, the response time of the valve was insufficient to prevent the low flow setpoint from being reached. The low flow trip is designed to protect the pump from potential damage caused by operation below minimum pump flow requirements. The 2A main feedwater pump suction safety relief valve lifted as a result of the relief valve set point (approximately 750 psig) being very close to system operating conditions post-trip. A review of the condensate and feedwater system (EIIS:SD) dynamics identified that the differential pressure of the condensate pump, which supplies the main feedwater pump, was capable of developing pressure at the suction of the main feedwater pump sufficient to lift the relief valve. This higher pressure (approximately 755 psig) may occur during the transient condition immediately following a plant trip and prior to the establishment of full recirculation flow in the Condensate System. The inadequate design margin for transient system performance was further compounded by improper temperature compensation during valve setup.

The pressurizer pressure and level response observed following the reactor trip was the result of recent improvements made in the Steam Bypass and Control System (SBCS) response. This system consists of automatic actuating valves which open on a reactor trip and are designed to accommodate turbine load rejection without opening the pressurizer or steam generator safety valves. The improved SBSC response resulted in a larger pressurizer level and pressure decrease than previously observed during trips prior to the implementation of the system improvements. The total change in average RCS temperature from approximately 574 to 535 degrees F remained the same for this event.

The 2C Auxiliary Feedwater (AFW) pump tripped due to over speed when AFAS-1 actuated. The pump was operating at the time, after starting during the actuation of AFAS-2, and had been operating for approximately 10 minutes. While pump over speed could not be duplicated during testing performed subsequent to this event, a response team investigating the event determined that the probable root cause of the over speed trip was from water induction into the 2C AFW pump turbine. It was concluded that during the 28 days since the last operation of this pump, moisture had condensed and accumulated upstream of the "A" train steam supply valve for the pump (MV 08-13). AFAS-1 actuated after the initial start of the 2C AFW pump, causing this steam supply valve to open and the accumulated water to be introduced into the turbine.



ANALYSIS OF THE EVENT

This event is reportable under 10 CFR 50.73 (a)(2)(iv), as an event or condition which resulted in a manual or automatic actuation of any engineered safety feature, including the Reactor Protection System.

Utility licensed operators manually tripped the reactor and turbine in accordance with the requirements of the Main Generator Off Normal Operating Procedure (ONOP), 2-2200030, due to increasing hydrogen gas temperature in the main generator to preclude equipment damage.

The plant response to this event is bounded by section 15.2.1.2 of the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR) which assumes a decreased heat removal by the secondary system due to isolation of the main turbine at 102 percent power. The actual plant response was more conservative than that described in the analysis for the following reasons: 1) The Unit was operating at 100 percent reactor power rather than the 102 percent assumed in the UFSAR. 2) The reactor and turbine were manually tripped by the operators and 3) SG pressures were maintained less than the main steam safety valve (MSSV) lift set points during the event. Additionally, both steam generators were maintained greater than 40 percent wide range level during this event and the capability of the steam generators t act as a primary heat sink was not adversely affected.

The temperature control valve which failed during this event controls the flow of Turbine Cooling Water (TCW) through the main generator hydrogen cooling heat exchanger. This system (TCW) is designed to provide a heat sink for the turbine cycle equipment during normal operation. The system serves no safety function and is not required to achieve safe shutdown or mitigate the consequences of any accident.

Loss of the 2B MFW pump and the lifting of 2A MFW pump safety valve SR 12470 following the trip did not affect the ability of the steam generators to act as a primary heat sink. Operation of the MFW system as a source of feedwater to the steam generators is not required to accomplish any safety related function and steam generator levels following the trip were maintained greater than 40 percent wide range at all times by auxiliary feedwater.

The 2C AFW pump tripped due to over speed during this event. The 2A and 2B electrically driven AFW pumps remained available during the event and were used to provide feedwater to the steam generators. The safety related functions of the 2C AFW pump include: 1) supplying sufficient AFW flow to both steam generators to avoid over pressurization of the Reactor Coolant System (RCS) during the most limiting operational conditions (i.e. station blackout) and 2) supplying sufficient AFW flow to the steam generators during accident or safe shutdown conditions to maintain an adequate RCS heat sink. Should the over speed of the 2C AFW pump occur during accident conditions, including station blackout, approved operating procedures are in place which provide direction for restarting the pump. Testing performed subsequent to this event supports the conclusion that the procedures for accomplishing a pump restart would be successful, as any additional moisture collecting in the steam supply line to the pump would take a relatively long period of time to accumulate.



ANALYSIS OF THE EVENT Continued

The pressurizer pressure response to the reactor trip from 100 percent power reached a lower value than previously observed. Post trip pressure decreased to a minimum of approximately 1870 psia which was lower than the prior nominal post trip pressure of approximately 1920 psia. A number of factors influence post trip pressurizer response, however in terms of level and pressure, the predominant influence is the change in RCS bulk temperature.

A review of Steam Bypass and Control System (SBCS) modifications made on Unit 2 during the last Unit 2 outage, indicates that recent improvements in system response due to changes in tuning parameters, valve trims, and strokes were primarily responsible for the increased cooldown rate observed. The plant simulator was used to confirm that a more rapid cooldown to hot standby conditions would result in lower post trip pressurizer pressure and level values. Although the post trip cooldown to Hot Standby was more rapid than previously experienced, it was well within the capability of plant control systems. Additionally, the more rapid SBCS response is beneficial, in that the frequency of Main Steam Safety Valve actuation is reduced.

All safety functions were met during this event, and based on this and the assessment provided above, it is concluded that the health and safety of the public were not affected.

CORRECTIVE ACTIONS

1) A Plant Change/Modification (PCM) was completed for TCV 13-15 which changed the mounting configuration of the valve positioner and minimizes the vibration experienced by the valve assembly. This PCM also eliminates the mechanical feedback arm from the positioner and therefore eliminates the failure mechanism leading to this event.

2) FPL evaluated the susceptibility of other temperature control valves to the failure mechanism which affected TCV 13-15. As a result, a modification was implemented to change 3 additional valves in the Turbine Cooling system, (TCV 13-28, TCV 13-2A and TCV 13-213) to a configuration which directly couples the valve positioner to the

actuator assembly. This modification reduces valve assembly vibration and eliminates the feedback arm as a component. The modification is currently completed for TCV 13-28 and TCV 13-2A. This modification will also be implemented on the corresponding Unit 1 valves.

3) A Plant Manager Action Item (PMAI) was initiated to provide circuit logic and cost estimates for implementing a modification to the MFW pump minimum recirculation flow control valves to improve performance. This action will be performed for both St. Lucie Unit 1 and 2.

4) The safety relief valve for the 2A MFW pump suction piping was removed and inspected following this event. FPL engineering reviewed the relief valve set point against vendor requirements including temperature compensation. As a result of this review the relief set point for the valve was increased from 750 psi to 780 psia in accordance with engineering recommendations.



CORRECTIVE ACTIONS Continued

5) FPL evaluated the pressurizer pressure and level response which was observed following this reactor trip. It was concluded that pressurizer pressure and level parameters responded as expected considering recent improvements which were made for steam bypass control system (SBCS) reliability. It is also concluded that the

response of these parameters was well within the capability of the plant control systems. A training bulletin was issued to on-shift operating crews which explains the primary system parameter differences observed during this event to ensure that all operators are cognizant of the effects of SBCS on post trip response. The need for simulator modeling changes will be reviewed and changes implemented if necessary.

6) A modification was completed for the 2C AFW pump which re-configures the steam supply warm up lines to eliminate the potential for long term moisture accumulation upstream of the 2C AFW steam admission valves. This modification will prevent the accumulation of moisture which could be introduced into the pump turbine during start up. This condition has not been observed on Unit 1, and piping elevations are different, however FPL is continuing to evaluate the configuration of the Unit 1 AFW system for generic susceptibility.

ADDITIONAL INFORMATION

Failed Components Identified

Manufacturer: Bailey Controls

Model number: 5321030A2

Device: Valve Positioner

Manufacturer: Ingersoll Rand

Model number: 4-HMTA-7-stage

Device: AFW Pump

Previous Similar Events

LER 389-96-001 "Manual Reactor Trip due to High Main Generator Cold

Gas Temperature" This event was due to the closure of

the hydrogen cooler TCV caused by a faulty derivative

setting in the valve controller.

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Florida Power & Light Company,

P.O. Box 128, Fort Pierce, FL 34954-0128

July 8, 1996

FPL

L-96-178

10 CFR 50.73

U. S. Nuclear Regulatory Commission

Attn: Document Control Desk

Washington, D. C. 20555

Re: St. Lucie Unit 2

Docket No. 50-389

Reportable Event: 96-002

Date of Event: June 6, 1996

Manual Reactor Trip Due to High Main Generator

Cold Gas Temperature Caused by Valve Failure

The attached Licensee Event Report is being submitted pursuant to the

requirements of 10 CFR 50.73 to provide notification of the subject event.

Very truly yours,

J. A. Stall

Vice President

St. Lucie Plant

JAS/EJB

Attachment

cc: Stewart D. Ebneter, Regional Administrator, USNRC Region II Senior

Resident Inspector, USNRC, St. Lucie Plant

an FPL Group company

*** END OF DOCUMENT ***